

**Senate Bill 1976 (Statutes of 2002, Chapter 850)**

**Draft Report to the California Legislature on Feasibility of Real-Time,  
Critical Peak, and Dynamic Pricing**

**June 9, 2003**

**Executive Summary**

Senate Bill 1976 (Torlakson, Statutes of 2002, Chapter 850) calls for the California Energy Commission, in consultation with the California Public Utilities Commission, to conduct an assessment, among other things,

*“...the feasibility of implementing real-time, critical peak, and other dynamic pricing tariffs for electricity in California, as strategies which can either reduce or shift peak demand...”.*

This report provides a status update on assessment activities conducted to date that support a feasibility study, the expected peak demand savings resulting from implementation of these different tariffs, a discussion of the barriers and challenges facing development of the tariffs, and recommendations for removing key statutory and regulatory constraints that would preclude successful implementation of real-time, critical peak and dynamic tariffs.

The California Energy Commission (Energy Commission), California Public Utilities Commission (CPUC) and the California Power Authority (CPA) have worked cooperatively to develop demand response programs that use prices as guides for customers to voluntarily reduce their electricity use and demand to avoid high prices. Preliminary investigations suggest that customers could adapt to dynamic pricing tariffs and reduce their peak demand accordingly. Assembly 29X (Kehoe, Statutes of 2001, Chapter 8) has already created the metering and communications infrastructure necessary to enable medium to large commercial and industrial customers to effectively respond to hourly electric pricing signals. An effort to develop to develop a metering and communications infrastructure for small commercial and residential customer classes is currently underway as a pilot program that began in July 2003 and is scheduled to be completed in December 2004. Dynamic pricing has been demonstrated as a viable concept in other states that can provide benefits to the entire body of electricity consumers.

Through introduction of appropriate tariff structures August 1, 2003, it is estimated that large commercial and industrial customers will be able to reduce their peak electric demand 500 megawatts (MW) by 2005. With development of additional tariffs and programs for all customer classes and refinements in equipment that will allow customers to respond to dynamic prices, it is anticipated that about 2,500 MW peak demand reduction could be achieved by 2007.

However, there still exist a number of implementation challenges and regulatory issues that need to be resolved before this magnitude of peak demand savings can be achieved. Discussions with stakeholders and policy makers have pointed to....

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## **Background**

After Californians experienced sudden increases in the wholesale price of electricity during the summer of 2000 followed by rolling blackouts during the winter, technological as well as regulatory solutions were sought as a hedge against electricity supply problems. Assembly Bill 29X (AB 29X, Kehoe, Statutes of 2001, Chapter 8) provided \$35 million for the installation of over 25,000 electric interval, or “real-time” meters as they are commonly called, in electric utility customer facilities greater than 200 kilowatts in demand. These meters also have the capability to communicate demand and energy usage information, thereby providing customers a new tool for managing their energy costs. AB 29X created the necessary metering and communications infrastructure that will ultimately enable medium to large commercial and industrial customers to effectively respond to hourly electricity pricing signals in a dynamic or real-time pricing environment. A similar effort is currently underway for the small commercial and residential customer classes. All that is needed now are the appropriate tariffs and customer programs. Senate Bill 1976 (SB 1976, Torlakson, Statutes of 2002, Chapter 850) was enacted with this purpose in mind. Many states currently have, or are in the process of implementing real-time rate tariffs. Since 2001, the California Energy Commission (Energy Commission) has been closely following proceedings in other states related to dynamic electricity tariffs and has been evaluating the feasibility of applying real-time, critical peak, and other dynamic pricing tariffs to California’s electricity market. Dynamic pricing tariffs have been demonstrated as a viable concept in other states that can provide benefits to the entire body of electricity consumers.

## **I. Introduction**

The overarching requirement of Senate Bill 1976 is for an assessment of:

*“...the feasibility of implementing real-time, critical peak, and other dynamic pricing tariffs for electricity in California, as strategies which can either reduce peak demand or shift peak demand...”*

Since this bill was adopted in late 2002, the Energy Commission and the California Public Utilities Commission (CPUC) have worked together to develop and implement time-of-use (TOU) pricing rates for some customers and critical peak prices (CPP) for others. Most recently, the California Power Authority (CPA) has also become a participant in this joint effort. CPP is essentially a hybrid rate form that lies halfway in the spectrum between fixed electricity pricing and prices that change as a function of market conditions (real-time pricing). The agencies decided it was important to pursue

this hybrid rate form first, both to help educate customers and because real time pricing was not yet available in the market during the first part of 2003. Preliminary investigations suggested that customers could adapt to CPP and reduce their peak demand accordingly.

This report also identifies the barriers and challenges that the legislature and the state's administrative agencies would need to resolve in order to achieve the levels of dynamic pricing that would improve the performance of the state's electricity system.

Implementation of increased levels of demand response is now commonly included in lists of what California should have done to reduce the electricity crisis of 2000-2001.<sup>1</sup> Further, since California utilities will continue to procure power from various bilateral and formal markets for the foreseeable future, many believe that such increased demand response should still be developed and implemented. The Energy Commission understands this report to have been required so that the legislature might better understand the feasibility of developing this demand response capability. Further, at the time this legislation was written, the state's energy agencies were not of one mind about the desirability of pursuing development of demand response; thus, the requirement that the Energy Commission prepare this report in consultation with the CPUC.

Much has changed since the legislation requiring this report was written. Up to that time, the Energy Commission had not been successful in persuading the CPUC to adopt real time pricing tariffs despite the perceived benefits of these tariffs and in the fact of the successful deployment of over 25,000 real-time price (RTP) metering systems funded through AB29X. The Energy Commission had sponsored several workshops, which highlighted the opportunities of dynamic pricing and other demand response programs being investigated or implemented by utilities around the nation.

In June 2002, the CPUC enacted rulemaking R.02-06-001 to investigate a wide range of topics related to dynamic pricing.<sup>2</sup> Shortly after that, the Energy Commission and the CPA were asked to join with the CPUC in guiding that proceeding. In the subsequent year, the Energy Commission, CPUC and CPA have worked cooperatively to develop various forms of demand response for those greater than 200 kW customers who already have RTP metering systems and to investigate demand response from residential and small commercial customers who do not yet have the appropriate metering and communication equipment.

Dynamic pricing tariffs and load bidding programs are relatively new additions to a portfolio of ways in which modifications to customer loads can help the electricity system operate more efficiently and reliably. Reliability has been the justification for interruptible rate and air conditioner load control programs that have been in place for more than twenty years. These traditional programs are triggered when the utility or the California Independent System Operator (CAISO), monitoring operating reserves predicts that such reserves will fall below minimum levels established by the Western Electricity Coordinating Council (WECC). In effect these programs are triggered when emergency action is needed, and interrupting some customers voluntarily is preferable to

emergency load shedding by rotating outages or outright system collapse. Participating customers typically receive a rate discount in return for a limited obligation to shed load upon request.

The term demand response includes these old emergency response programs and new approaches that use prices as a guide for consumers to voluntarily cutback for those end-uses and to the degree that consumers wish to avoid high prices.

As a result of 2000-2001 market dysfunction, some do not believe that price should be used as a tool to motivate demand response. They wish that prices could be firmly controlled and not exhibit any volatility. These persons seemingly oppose creation and use of dynamic pricing tariffs and programs. Unfortunately, the reality of electricity generation is that costs can vary quite strongly across the hours of the year. Eliminating nefarious market power abuses by merchant generators does not mean that it costs the same to provide electricity at all times of the year.

Even in the old integrated utility world, the fact that California has a sharply higher demand in the summertime to provide air conditioning comfort and respond to other loads peaking in the summer season, meant that high-cost generation from power plants not normally used would be brought into service and dispatched. As the system balance was tipped closer and closer to its maximum level, increasingly costly facilities were brought on line. Because California relied almost entirely upon annual average pricing for most electricity, and did not convey these time-differentiated costs to consumers, we have little history to understand how customers might respond to time-differentiated pricing. However, it is theoretically true, and has been demonstrated in numerous other locations around the country, that dynamic pricing does work, can be acceptable to participants, and can provide benefits to the entire body of electricity consumers whether they all participate in it or not.<sup>3</sup>

Academic experts also make a convincing case that if there are potential abuses of market power in a hybrid or fully competitive market structure, which California clearly knows to be possible, that dynamic pricing can be a good way to reduce or eliminate these abuses.<sup>4</sup> Because California will continue to rely upon bilateral contracts and market-based purchases supplied by merchant generators, even if it wanted to return to an exclusive utility controlled industry design, pursuing some degree of dynamic pricing can be a tool that helps to ensure that the prices of power in these markets is as little affected by market power as possible.

To implement dynamic pricing tariffs and programs requires that markets have transparent prices upon which to base a customer tariff. Since the demise of the California Power Exchange and secretive procurement by the Department of Water Resources (DWR) in 2001-2002 and now utility procurement practices, California has lost the most valid, transparent source of market prices. Because of this, the original thrust of collective agency efforts toward implementation of real-time pricing tariffs has been temporarily redirected into other forms of dynamic pricing until the CAISO recreates an acceptable, transparent market price signal.

As a starting place for a lengthy examination of many kinds of dynamic pricing tariffs for all customer classes, the joint agency activities have focused upon the customers with peak loads greater than 200 kW who have the AB 29X RTP metering systems in place.<sup>5</sup> These are primarily medium- to large commercial buildings, industrial customers, and some water agencies. In a decision adopted June 5, 2003, the CPUC has implemented two alternative ways in which customers may voluntarily participate in dynamic pricing. CPP tariffs used administratively pre-determined rates on 12 CPP days each summer season triggered by temperature conditions likely to be correlated with high spot market prices or use of high cost utility-controlled generators. Load bidding programs allow customers to identify specific price levels at which they are willing to shed a pre-determined amount of load in return for being paid the utility's avoided cost. Neither of these rely upon a market price, but they can be readily modified to use a market price trigger once one becomes available. RTP tariffs are being developed in a second phase of the joint agency proceeding, and these proposals should be ready once the CAISO implements Day-Ahead markets with valid hourly prices in spring 2004.

The voluntary tariffs and programs recently implemented are just opportunities unless they attract substantial numbers of customers willing and able to participate on a sustained basis. Only then do they result in an active demand response capability that can discipline market power and provide benefits to both participants and electricity consumers at large. Frankly, California electricity consumers are jaundiced. They have been burned by poor market performance and asked to pay for enormous amounts of sunk costs from utilities and DWR. In most customer classes, bundled service rates are now the highest in the country. In most hours of the year market prices (as measured by bilateral contract trading indices and CAISO real-time prices) are far below average rates. It is expected that participation in these CPP tariffs and load bidding programs will be low at first. Incentives will be offered on a transitional basis so that enough choice to "pilot" these efforts that the participation issues can be thoroughly understood. The agencies plan that participation in these initial programs will grow through time and contribute toward a goal of five percent of peak load, or about 2,500 MW by 2007. Additional tariffs and programs for larger customers and some form of tariffs and programs for smaller customers will also be needed to achieve these goals. This capability will displace the need to build large numbers of combustion turbines held in standby for peaking purposes, using up scarce generating facility locations and limited offsets needed by all facilities requiring New Source Review air quality permits.

At this time there is no need to coerce unwilling end-users to participate in dynamic pricing tariffs and programs even if traditional cost allocation principles mean that such tariffs should be the default for all customers. Relying upon voluntary participation will help to gain needed experience and allow programs to be fine-tuned for greater participation later. The traditional disconnects between actual costs of service and rates for most customers that can be eliminated through the knowledge of each customer's usage pattern by the RTP metering systems mean widespread cross subsidies that should be removed carefully, and with transitional assistance where appropriate. In addition, the technologies to allow end-users to respond quickly and as painlessly as possible are just now emerging from research labs and high tech entrepreneurs. Additional refinement is

needed before the agencies fully understand the best means to ensure that end-users have the equipment that will permit them to respond to dynamic prices with customer needs sensitive, automatic control devices rather than manually turning the air conditioner on and off.

The largest unresolved question before the agencies is not the feasibility of dynamic pricing for all customers classes, it is whether the costs of universal deployment of advanced metering and automatic control equipment so reduces the costs per unit that even small usage customers receive net benefits from the value of the information and an ability to more completely control their total costs. This question is being addressed, in part, by a major price response experiment for residential and small commercial end-users being pursued as a result of CPUC D.03-03-036. This effort will begin in summer 2003 and continue through 2004 in order to develop an understanding of how these small customers respond to various price patterns, with and without automatic control equipment. This understanding will be a key input into the question of universal deployment of advanced metering systems. At this point it is unclear whether California will follow the lead of many utilities around the country and install these systems,<sup>6</sup> or whether we will settle for some smaller scale deployment focused just on particular classes of customers.

## **II. Roadmap of Report**

To facilitate reading, the chapters of this report are organized into distinct discussion topics, each meeting one or more of the seven different legislative requirements of SB 1976. Applicable requirements are annotated in italics within the particular chapter addressing the requirements. The content of each of the report chapters is briefly stated below.

- Chapter I provides a background on California's electricity pricing environment, a status report of the work from the ongoing proceeding for investigating the feasibility of dynamic electricity pricing, lessons learned thus far, and estimated magnitude of peak demand savings to be expected from time-varying tariffs.
- Chapter II describes the structure of the report.
- Chapter III reviews progress in developing time-varying tariffs and defines critical peak pricing concepts for different customer classes.
- Chapter IV identifies important policy issues raised in agency proceedings that could require legislative review or action.
- Chapter V addresses questions raised in SB1976 with respect to the feasibility of implementing time-varying rates and real time rates (hourly changes) for specific customer classes, and the potential for these rates to provide benefits to all customers by making changes in wholesale markets.

- Chapter VI provides a qualitative assessment of the benefits and costs of time-varying pricing.
- Chapter VII provides a forecast of the likely level of megawatt reductions and other benefits that can be expected from the implementation of these rates.
- Chapter VIII discusses strategies that can be used to safeguard vulnerable customers who may not prefer to be exposed to dynamic prices.
- Chapter IX identifies barriers and challenges to the implementation of these rates that may require legislative and/or agency action.
- Chapters X and XI provide recommended agency and legislative actions necessary for supporting the implementation of time-varying electricity tariffs in California.

### **III. Procedural Background**

California's energy agencies since the 1970's have focused on the need to provide customers with more accurate. Pioneering experiments on time of use pricing were performed in the late 1970's and California had active load management programs during most of the 1980's. Unfortunately agency attention was diverted to and focused entirely on the supply side of the market during the restructuring experiment of the late 1990's. As a consequence, the customer side of the market was totally unprepared for the unanticipated large price spikes that created an electricity crisis in late 2000 and persisted until the late spring of 2001.

#### **A. Review of Energy Actions During 2001 – 2003 to Promote Dynamic Pricing**

Since that time, California's energy agencies actively sought to increase the level of customers' contribution to solving the electricity crisis in three distinct ways:

1. Developed and implemented a new generation of energy efficiency and demand response programs under funding provided by Bill 5X (SB 5X, Sher, Statutes of 2001, Chapter 7) that offered incentive payments to commercial and industrial customers providing verified load reduction in their facilities,
2. Developed and implemented a mass media campaign (Flex Your Power) to encourage voluntary customer reductions by carefully managing the use of air conditioners and appliances during hot summer afternoon peak periods.
3. Developed implemented a plan under funding provided by AB 29X to rapidly install new real-time interval meters so that large customers could respond to rapid increases in cost of delivering electricity during peak periods.

Each of the three programs described above are reviewed in more detail below.

- **New Program Deployment:** the Legislature provided funding for a broad array of energy efficiency and demand response programs to provide customers with information and necessary building control tools to combat or adapt to the large spikes in prices and associated reliability problems first noticed in May of 2000. The Legislature provided \$10 million under Assembly Bill 970 (AB 970, Ducheny, Statutes of 2000, Chapter 329) for the Energy Commission to develop and implement demand response programs in July of 2000. This amount was increased later to over \$40 million in February 2001 under funding provided by Senate Bill 5X (SB 5X, Sher, Statutes of 2001, Chapter 7) for the Energy Commission to implement demand response programs and \$10 million for smart thermostat pilots supervised by CPUC. These programs were able to achieve 250 MW in demand response capability by the summer of 2001. This program was put to a test during a Stage 2 event on July 3, 2001, when over 150 MW of peak load reduction was delivered.
- **Flex Your Power Campaign:** Review campaign and purported peak savings.

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- **Real-Time Meter Deployment:** the Legislature took the lead in providing \$35 million in funding under AB 29X to install advanced real-time metering systems in April of 2001. Over 25,000 meters were deployed over a 16 month period in both investor owned and municipal utility service areas where utilities and customers had a strong desire to give customers more information about prices and more control over their energy bills.

California's electricity market eventually stabilized in summer of 2001 as many of the programs described above were successful in catalyzing over 5000 MW in peak demand reductions. At this point, agency staff began to develop additional new programs to make the emergency savings achieved during this critical period into sustainable peak demand reductions.

Agency staff worked together in the fall of 2001 and spring of 2002 to develop an action plan to develop a permanent demand response capability. The action plan was drafted and discussed in a series of public workshop in May of 2002 and published in June of 2002 on the Energy Commission's web site.

Commissioners from the Energy Commission, CPA and CPUC reviewed this action plan and decided to take action by implementing some of the recommendations contained therein. The CPUC adopted Order Instituting Rulemaking R.02-06-001 in July of 2002 and the Energy Commission followed suit shortly thereafter in August of 2002. Under this rulemaking, the agencies agreed to pursue three main policy goals:

1. Achieve more price response from customers by developing new time-varying tariffs and offering customer choice of tariff forms.
2. Achieve more demand response MW savings from customers through well-coordinated programs.
3. Reduce economic and environmental costs of meeting California's needle peak demands for fifteen days per year through a combination of proper pricing and demand response programs.

#### B. Development of Proposals for Critical Peak Pricing Tariffs and Statewide Residential/Small Commercial Pilot

SB 1976 directs the Energy Commission to describe proposals for critical peak pricing tariffs for commercial customers and to discuss the decision to proceed with statewide residential/small commercial pilot for the next 18 months.

*Legislative requirement 2(b)(4): "An assessment of the options for a variety of customer classes, including, but not limited to, industrial, commercial, residential, and tenants of a mobile home park, apartment building, or similar residential complex, that receive electricity from a master-meter customer through a submetered system."*

Since 2002, the Energy Commission has been closely monitoring a number of other California proceedings relating to various utility and *ex parte* tariff proposals for different electric customer classes. Energy Commission, CPUC and CPA staff had been conducting a joint proceeding to develop new time-varying tariffs for all customer classes. A pilot test of new tariffs and controls technology for residential and small commercial customers is anticipated to begin in July of 2003 and continue until December of 2004. Educational materials that explain new tariff forms and that are designed to educate customers about their available options to reduce peak usage and thus their monthly bills were mailed on June 10, 2003.

A primary goal of this pilot test research effort is to obtain an estimate of how much customers as a whole reduce their usage in response to both static time of use and dynamic CPP rates and to learn more about customer's preferences for different forms of dynamic rates. Armed with this information, agency staff plan to analyze whether or not it would be wise for the state to deploy new RTP meters and the associated dynamic tariffs to some or all residential customers over the next five years. This analysis should be complete by fall of 2004.

New tariff forms were introduced for large commercial and industrial customers August 1, 2003, with a goal of reducing 500 MW of peak electric demand by 2005 <TO BE UPDATED>. The next chapters of this report describe some of these new time-varying tariffs, and discuss some of the anticipated benefits from their use.

#### **IV. Important Policy Issues Raised During the Proceedings**

##### **A. Default Tariffs for all customers.**

Hourly costs to provide service for California's electric utilities varied substantially under both conventional and restructured regulatory frameworks. The fact is that the cost of production, whether the resources are owned by the utility or a merchant provider, has always been less expensive for baseload than for peaking resources. Since collective customer usage patterns require a mix of both types of resources, costs vary accordingly. Although hourly cost variation has been a characteristic of the electric utility industry since it began, the ability to measure and bill customers accordingly has not been either practical or economical until recently.

Electric utility tariffs generally describe both the rate or prices the customer pays for service as well as the rules under which that service is provided. For purposes of this section, all reference to tariffs will almost exclusively pertain to the rate design or pricing structure.

Traditionally, electric utility tariffs were designed based on cost of service principles, where the objectives were to allow utilities to recover all costs of providing service and also assure that individual customers and classes of customers each paid their fair share of costs based on usage metrics. Cost of service determinations segregate costs into three areas: (1) customer service costs, which include billing, account management, and service establishment; (2) demand costs, which include allocations for system transmission and distribution investments as well as customer site-specific equipment necessary to serve the customer's maximum hourly usage, and; (3) energy costs, which include volume-based charges to reflect customer metered usage during a defined billing period.

Prior to the mid 1970's, all tariffs were based on a forecast of expected period usage (kilowatt hours) and estimated total costs for a future year defined to coincide with a rate case period. Once approved, the forecast became the utility revenue requirement. Dividing the revenue requirement by the expected annual usage yielded the rate or unit charge used to compute the customer bill.

From the early 1900's through the mid 1970's, the industry growth and construction of large central generating stations produced economies of scale that resulted in over 70 years of unit electric costs that declined with increases in total usage. Continually declining costs eliminated most tariff options and resulted in default declining block tariffs for all customers.

In the early 1970's, the oil embargo, environmental awareness and other structural changes permanently converted the utility industry from a declining to an increasing unit cost structure. A slow response to this change in cost structure and fuel shortages prompted the Federal passage in 1978 of the Public Policy Regulatory Policies Act (PURPA). PURPA established revised rate making standards that included:

- Cost of service – rates should reflect the costs of providing service and methods for determining differences should account for variation in daily or seasonal time-of-use and customer demand

- Declining Block Rates – energy components of rates should not decline with increased usage unless justified by the utility cost of service.
- Time-of-Day rates – rates should be based on costs of providing service at different times of the day if the long-run benefits are likely to exceed metering and other related costs.
- Seasonal Rates – rates should vary by season to reflect any cost variation
- Interruptible rates – industrial and commercial customers should be offered interruptible rates that reflect the cost of providing such service
- Load Management – consumers should be offered load management options to the extent they are practicable, cost effective, and reliable and provide useful energy or capacity management advantages to the utility.

In response to PURPA, from 1978 to 1980 the CEC and CPUC conducted a series of joint pricing and load management pilots that resulted in three major policy initiatives that still form the foundation for all current rates and demand response offerings, specifically:

- Default TOU rates were mandated for all C/I customers with demands greater than 500 kW. In September 2001 the CPUC extended the mandate for default TOU rates to all C/I customers with demands greater than 200 kW (A.00-11-038).
- Declining block rates were abolished and seasonal tiered rates, that increase the unit cost with increased total usage, were adopted for all residential customers. Metering costs prohibited the cost effective development of TOU or other more finely tuned rates. In 2001, AB1x, further clarified the tiered rate structure as well as which customers were exempt.
- In 1980, Load management standards were adopted and each of the three investor owned utilities were mandated to implement voluntary water heater and air conditioner load control programs. These programs spurred the development of complementary interruptible and curtailable rates and other demand response programs. In March 2001, CPUC D.0103073 in response to AB970, initiated a research program to examine the potential for remotely controlled thermostats.

Although there have been numerous CPUC and legislative rate adjustments over the years, most customers today still face default tariffs based on technology and cost relationships derived in the late 1970's and early 1980's. With the exception of the TOU tariffs mandated on C/I customers (demands greater than 200kW), default tariffs at best reflect only seasonal variation in costs: none reflect hourly cost variation. Today, approximately 99 percent of California's electric customers see default tariffs that charge them the same price for energy whether consumed at 3:00am or 3:00 pm, even though costs for that those hours may vary by a factor of 100 or more. In effect, current rates fail to establish a true link to the cost of service. As the CPUC's remotely controlled thermostat program demonstrates, technology changes in the last 20 years warrant reexamination of current policies and practices.

While some customers can voluntarily select from among a declining inventory of demand response or other pricing options, most customers have little or no choice in what level or cost of service they receive. More significantly, collective legislative and

accounting changes over the last 20 years have resulted in rates too complex for most customers to understand. In essence customers have no choice in what rate they receive and even less opportunity to control what they pay in their monthly bill.

As part of the rulemaking in R.02-06-001, the joint CPUC, CEC and CPA policy group sought to simultaneously reduce the complexity and improve the cost accountability of existing tariffs. The policy group established a vision statement that suggests a reordering of default tariff options for all customers. There were two basic components to the joint vision statement:

1. By 2007, all California electric consumers should have the ability to increase the value derived from their electricity expenditures by choosing to adjust usage in response to price signals.<sup>7</sup>
2. Customers should have the option to select from among a variety of tariff options. Critical peak pricing should be established as the default tariff; however, customers should have the option to select from among risk adjusted TOU and flat rates. The largest C/I customers should also have the option to select real-time pricing options.

The joint vision statement raises several significant policy issues that are now being examined in a continuing series of regulator working sessions and a statewide pilot program. There are several economic, operational, and practical reasons to reconsider the new default tariff position and customer choice advocated by the policy group vision statement. Ultimately, the proposed vision statement constitutes a new electric pricing policy for California. The key issues include:

- The same advanced metering and communication systems necessary to support critical peak pricing and customer choice can provide electric and gas utilities with substantial automation efficiencies and internal operating benefits that would seem to be a logical part of any business improvement and modernization effort. Furthermore, these systems can provide all customers with information for better managing and understanding their energy usage and investment decisions. Should these metering and communication costs just be considered a cost of service or should they be attributed only to implementation of the vision statement? Or should these costs be allocated in some fashion between normal utility operations and the cost of implementing the vision statement?
- California's electric pricing policy is directly reflected in what is established as the default tariff. Establishing critical peak pricing as the default electric tariff, while simultaneously providing customers with other optional risk adjusted rate options, preserves customer choice but clearly states that rates should reflect the cost of service. Establishing critical peak pricing only as a voluntary rate option, reflects a pricing policy that does not support the link between energy usage and cost of service. Which pricing policy is most appropriate for California?
- Universal deployment of the metering and communication systems necessary to implement a default critical peak pricing policy can be accomplished at significantly reduced unit costs than a piecemeal, customer-by-customer

approach. Do the economies of scale, utility cost savings and information benefits for all customers justify universal deployment?

- Establishing a functional metering and communication infrastructure for all customers promotes choice and provides a capability to quickly respond with alternative rate options to mitigate naturally caused reliability, high cost or market abuse situations. Do these potential benefits offset the small potential incremental costs of implementation and the opportunity costs of not being able to respond to the next market situation?

#### B. Cost Effectiveness of AMR Deployment

The dynamic pricing options considered in this proceeding are structurally different from load control, interruptible and curtailable rates and other conventional demand response programs. Conventional programs are designed for a hypothetical ‘average customer’ that simplifies or eliminates the need for advanced metering by using fixed participation incentives, fixed rates, and/or fixed curtailment obligations. Under conventional programs, all customers receive the same benefits regardless of how they actually respond. While this approach reduces initial program costs, the inability to link incentive payments to how customers actually respond creates program efficiency and equity problems that quickly offset any apparent cost advantage. The inability to link incentives to actual customer actions, the inability to reflect time-dependent system costs, and the inflexibility inherent in fixed load reduction commitments all impact program production and customer participation.

In contrast, while dynamic pricing requires advanced metering to support dispatchable critical peak prices, price-based incentives eliminate all equity, efficiency, and operating flexibility issues. Participation issues are also resolved, because customers decide for themselves if, when and how to respond.

The need for advanced metering raises a critical question regarding cost allocation and how metering should be treated in a demand response cost effectiveness analysis. There are three possible alternatives for addressing cost allocation, each with different impacts on cost effectiveness and implementation.

##### 1. The Business Case Financially Justifies Advanced Metering Implementation.

Utilities usually treat the cost of metering as a business operating issue. As such, decisions to upgrade to more advanced capabilities are usually determined by a business case or independent financial analysis that links implementation to operational cost savings and expected strategic value. For example, during OIR workshops in September 2002, Puget Sound Energy (PSE) and Pennsylvania Power and Light (PPL) both presented business case results that showed system-wide advanced metering was financially justified by internal cost savings alone. Neither business case included any benefit from demand response. In both cases, advanced metering became a cost of service.

Because metering is already installed and considered a cost of service, any subsequent implementation of dynamic pricing by either PSE or PPL will only have to address the infrastructure costs lowers the demand response necessary to achieve cost effectiveness, which extends potential implementation to a much wider segment of the small customer market.

2. The Business Case Cannot by Itself Financially Justify Advanced Metering Implementation.

If the utility business case cannot financially justify implementation only on the basis of internal cost savings, then cost and other benefits from the actual customer demand response may have to fill the benefit gap. The size of the benefit gap determines the demand elasticity necessary to satisfy the business case. The larger the gap, the higher the demand elasticity necessary to satisfy the business case. The statewide pricing pilot has been structured to address this scenario.

3. Demand Response Bears the Burden for All Infrastructure Costs.

Allocating all costs of advanced metering only to dynamic pricing substantially raises the level of demand response necessary to achieve cost effectiveness. Much greater demand response would be necessary to offset the full infrastructure cost. Under this approach, demand response will almost certainly be restricted to only the very largest C/I customers. Small C/I and almost all residential customers would be excluded. Targeted implementation will also eliminate any economies of scale (meter acquisition and implementation) as well as most internal utility operational cost savings, which will act to further restrict the potential target market. The likelihood of this scenario is very unlikely.

Unfortunately, the traditional utility business case is governed by the Standard Practice Cost Effectiveness methodology that focuses only a restricted subset of actual utility, customer and system impacts. Examples of benefits not considered by the Standard Practice include:

- Improved Customer Services – Traditional business case analysis assigns little if any value to improvements in customer service. Existing service levels are indirectly assumed to be already at an optimal level.
- Increased Revenues from New Customer Services – The advanced metering infrastructure creates an information base that can supply a number of additional fee-based customer services. Additional revenues from additional services are not included in the utility business case.
- Reduced Customer Costs – Neither the Standard Practice cost effectiveness analysis nor the utility business case provide any credit for the benefits customers receive from the advanced metering infrastructure. Electronic billing, coordination of meter reading cycles, access to usage information, and other benefits are generally assigned no value.
- Strategic Opportunity Costs – The ability to quickly implement rate options in response to extraordinary market conditions can have tremendous value. The outages experienced in California during 2000-2001 provide a prime example. Access to an advanced

metering and communication infrastructure could have provided short-term pricing and demand management options that could have reduced or prevented rotating outages.

C. Estimate of potential peak load reductions by class.

Over the last 25 years there have been numerous studies by California investor owned and other utilities to examine peak load and energy impacts from a wide variety of rate and pricing structures. The historical literature was extensively reviewed and documented in a formal report as part of the OIR working group process (Table 1). In addition, there have been several independent evaluations of the literature that further describe and clarify customer demand response. Tables 2 and 3 and Figure 1 provide results from a recent paper submitted to but not yet published by an industry journal.

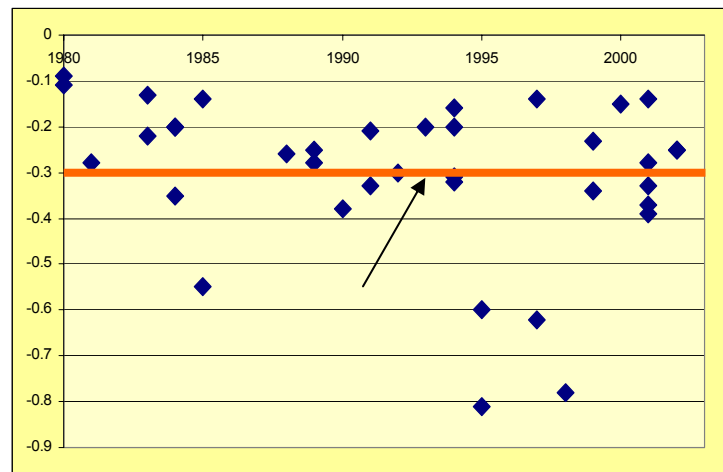
**Table 1. Customer Demand Response Estimates<sup>8</sup>**

<b>Program Type</b>	<b>Range of elasticities</b>	<b>Range of peak demand reduction</b>	<b>Range of total usage reduction</b>
Residential time-of-use	<b>-0.05 to -1.3</b> <i>(SCE; North Carolina)</i>	<b>4% to 35%</b> <i>(Ontario; Duke)</i>	<b>0% to 23%</b> <i>(PG&amp;E; Connecticut)</i>
Residential critical peak pricing	<b>-0.35 to -0.82</b> <i>(GPU; EdF France)</i>	<b>42% to 59%</b> <i>(Gulf Power; AEP)</i>	<b>0% to 6.5%</b> <i>(AEP; Gulf Power)</i>
Small commercial time-of-use	<b>-0.03 to -0.04</b> <i>(SCE; PG&amp;E)</i>	None reported	<b>2.1% to 5%</b> <i>(McKinsey multi-utility data; Finland)</i>
Small commercial dynamic pricing	No studies	No studies	No studies

**Table 2. Summary Statistics for 56 Elasticity Analyses<sup>9</sup>**  
*The Low and High Values Bracket the 95 Percent Confidence Band<sup>10</sup>*

<b>Geography</b>	<b>n</b>	<b>Short-Run Elasticity<sup>11</sup></b>		
		<b>Low</b>	<b>Medium</b>	<b>High</b>
California	13	-0.13	-0.21	-0.28
U.S.	36	-0.23	-0.28	-0.34
Other industrialized countries. <sup>12</sup>	7	-0.28	-0.47	-0.66

**Figure 1: Elasticities in 36 Studies Published Between 1980 and 2003 Show an Average Reduction in Usage of 30% for Every 100% Increase in Price <sup>13</sup>**



**TABLE 2: Residential Response to Time-of-Use Rates Across Several Experiments Calculated as Substitution Elasticities<sup>14</sup>**

<i>Experiment</i>	<i>Estimate of Elasticity of Substitution</i>
Carolina Power & Light	0.19
Connecticut	0.10
Los Angeles 1	0.19
Los Angeles 2	0.16
Los Angeles 3	0.13
Los Angeles 4	0.10
Los Angeles 5	0.13
Los Angeles 6	0.12
Los Angeles 7	0.11
SCE 1	0.14
SCE 2	0.16
Wisconsin 1	0.13
Wisconsin 2	0.13
Wisconsin 3	0.13
Pooled Estimate	0.13

*Source: Caves, Christensen, and Herriges (1983).*

The statewide pilot is designed to fill the gaps identified in Table 1 and to reduce the uncertainties inherent in existing response results reported in the other accompanying tables and figure. The results of the existing literature, when combined with results from the pilot, will provide the CPUC with a database that can be used to accurately predict demand responses for new California programs.

However, it is important to remember that all reported results including those from the OIR sponsored pricing pilot, are derived from experiments that have substantial limitations. Experiments typically measure only short-run elasticities, those changes in usage that customers can accommodate by modifying their existing lifestyle patterns and

equipment. These experiments do not measure long-term elasticities that might reflect customer moves to more efficient equipment or more permanent structural changes to reduce overall energy usage. In addition, all experiments are subject to experimental design, customer education, random uncontrollable weather and other environmental conditions, and pilot implementation problems, which can substantially affect both the validity and degree of customer response.

#### D. Availability of Real Time Price Data.

Only a summary of issues surrounding price data availability is given here since these issues were discussed in more detail in Chapter I. The lack of availability of real time price data are mainly due to the fact that:

- Dynamic pricing tariffs and load bidding programs are relatively new additions to a portfolio of ways in which modifications to customer loads can help the electricity system operate more efficiently and reliably.
- California historically has relied almost entirely upon annual average pricing for most electricity, and did not convey these time-differentiated costs to consumers. There is little history to understand how customers might respond to time-differentiated pricing.
- Implementation of dynamic pricing tariffs and programs requires that markets have transparent prices upon which to base a customer tariff. The demise of the California Power Exchange, procurement practices by DWR in 2001-2002 and current utility procurement practices led to the loss of the most important source of transparent market prices. As a result, the original thrust of collective agency efforts toward implementation of real-time pricing tariffs has been temporarily redirected into other forms of dynamic pricing until the CAISO recreates an acceptable, transparent market price signal.

#### E. Pilot tests being conducted to resolve some of these issues.

The overall objective of the Statewide Pricing Pilot (SPP) is to produce information to guide the decision on full-scale deployment of dynamic tariffs.

Dynamic tariffs as defined under the SPP, reflect a hybrid product that combine the strengths of conventional TOU and load control rates. Like conventional TOU rates, dynamic tariffs use seasonal two (peak and off-peak) or three-part (peak, partial and off-peak) time periods to reflect the time varying average cost of energy. Conventional TOU can usually capture the cost variation for most hours during a typical year. However, approximately one percent or less than 100 hours per year often reflect wildly different costs or reliability conditions that cannot be represented by an average period cost. Load control options were specifically designed to address these critical peak hours. Dispatchable control signals used to automatically reduce customer water heater and air conditioner usage during critical peak hours are in effect proxies for very high price and/or critical reliability conditions.

Dynamic pricing combines the TOU rate design for the base 99% of the hours during a year, with a dispatchable critical peak price that in fact becomes a substitute for a proxy load control signal. However, unlike direct load control, under dynamic tariff the customer makes all decisions regarding what, when and how much to control.

To properly calibrate and compare results, the SPP is designed to measure electric consumption and coincident peak demand impacts for three different tariff options, including:

1. Conventional time-of-use (TOU) - TOU rates under the SPP feature higher prices during one or two peak periods and lower prices during an off-peak period.
2. Fixed critical peak pricing (CPP-F) - CPP-F rates have also been referred to as day-type TOU rates. In effect CPP-F includes a normal day TOU rate and a critical day TOU rate. The normal day TOU rate is in effect on most days of the year. The critical day TOU rate, which incorporates a much higher on-peak charge, would apply during the ten to fifteen either highest cost or more critical reliability days of the year. Under CPP-F, customers receive day ahead notification to alert them to a critical day. The higher on-peak price is fixed for the entire duration of the on-peak period.
3. Variable critical peak pricing (CPP-V). CPP-V rates differ from CPP-F rates in that the critical peak period may be called on the day-of the event and unlike CPP-F, the higher on-peak price only applies to the few critical peak hours, not necessarily the entire peak period.

The SPP incorporates a sophisticated experimental design that includes residential and small commercial/industrial customers in all three utility service areas. The experimental design and sampling plan were designed to balance cost against the potential value of information received. The SPP also incorporates complimentary technology options and market research to further embellish and support the decision process. Table 4 provides a summary of the pilot proposals included in the SPP.

**Table 4. Summary of Pilot Proposals<sup>15</sup>**

<b>Proposal Name &amp; Sponsor</b>	<b>Dynamic Rates to be Tested</b>	<b>Targeted Population and Sample Size</b>	<b>Equipment to be Installed</b>	<b>Proposed Budget</b>
Statewide Pricing Pilot or SPP (Utilities, CEC, SFCPC, others)	2-period TOU, fixed CPP, variable CPP	1,520 residential 540 small commercial	Interval meter, enabling technology for some customers	\$9.6 million
Home Control Alternative (Invensys)	None. (Pay for performance)	3,000 residential	Interval meter, gateway, smart thermostat	\$5.5 - 7.5 million
T&D Control Pilot (IMServ)	None. (Pay for performance)	1,000 small commercial	Interval meter, gateway	\$2 million

Consistent with the comments made under Section C of this chapter, there are substantial limitations to the potential information expected from the SPP. Most critical of all limitations is the short-implementation period, which required substantial compromise in the customer marketing and educational tasks. Demand elasticities reflect customer changes in usage in response to a change in price, however, these measurements assume customers recognize and understand the price change and are knowledgeable regarding techniques for responding. Demand elasticity measurements will err on the low side, to the extent that marketing and educational efforts inadequately address these customer needs.

In addition, even under the best of circumstance, the SPP can only succeed in measuring very short-term demand elasticities that may not be representative of long-run customer adaptation. Customer response to high prices and reliability concerns during the 2000-2001 California electricity crisis demonstrated substantial demand elasticity and a willingness to respond. It is unlikely those types of results could ever be reproduced during the limited term SPP.

## **V. Feasibility of Providing Customers with Choice of Dynamic Tariffs**

SB 1976 directs that the Energy Commission examine the feasibility of providing customer classes with different dynamic tariff options, including how wholesale real-time prices would be calculated. The legislation also directs that options for incorporating demand responsiveness be assessed.

*Legislative requirement 2(b)(2): “Options for day-ahead and hour-ahead retail prices.”*

*Legislative requirement 2(b)(3): “Options for facilitating customer response to real-time and critical peak prices and managing total customer costs, including, but not limited to, interval metering and communications systems, consumer-side of the meter notification, and automatic response equipment.”*

*Legislative requirement 2(b)(1): “How wholesale real-time prices would be calculated and made available to customers.”*

*Legislative requirement 2(b)(6): “Options for incorporating demand responsiveness into the wholesale competitive market and operations of the California ISO.”*

#### A. Defining Dynamic Tariffs

Conventional flat, tiered, and time-of-use tariffs were designed to reflect and recover utility costs during an era characterized by relatively stable or declining costs. For example, if the hourly cost of producing and delivering energy during each hour of the year was identical, then a flat all-energy tariff that charged the same price in each hour would be both equitable and designed consistent with cost of service principles (Chapter 4). Under relatively stable conditions, the average prices reflected in each of these tariffs can adequately represent the cost of service. However, when costs vary substantially across seasons or during the day due to production or delivery factors, conventional tariffs fail to adequately reflect the cost of service.

For at least the last 20 years, hourly electric system costs nationwide and particularly in California, have tended to reflect a highly skewed distribution characterized by a few very high cost hours each year. Figure 1 provides an example partial price duration curve for the mid-continent area power pool. This figure illustrates not only how hourly prices can vary within a year but also how they can vary from one year to the next. Using the price duration curves in Figure 1, it is easy to see that a flat rate, one that charged an average price for each hour in the year 1999 would fail to properly reflect the 10 highest cost days as well as the same rate might in the year 2000.

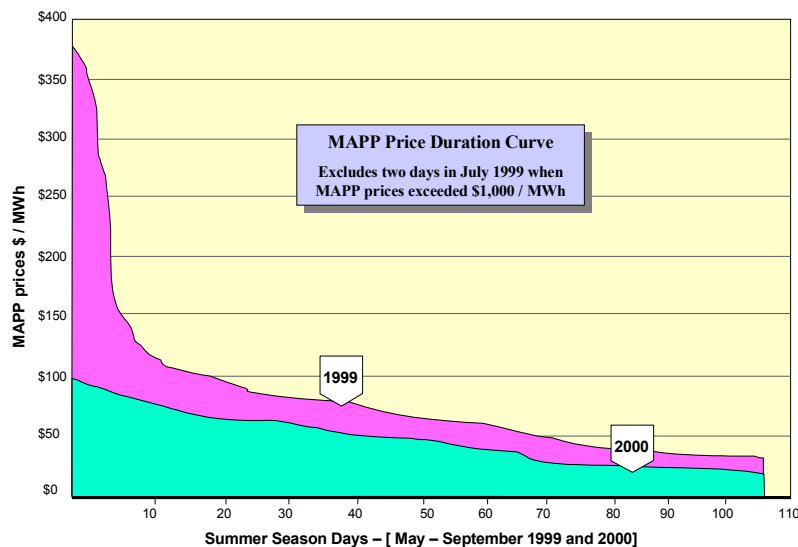


Figure 1. Example Price Duration Curves

Unfortunately for California, our rapidly growing population, extreme differences between coastal, inland and mountain areas and a dependence on hydro generate annual price duration curves similar to the Figure 1, 1999 data.

Dynamic tariffs are specifically designed to address the within- and between-year price volatility illustrated in Figure 1. Dynamic tariffs accomplish this with rate designs that include at least one variable or dispatchable price targeted at the top 10-15 days or 100 hours of extraordinary costs. When the utility system experiences high cost, the dispatchable rate component is activated. The dispatchable rate component is not used if the utility system doesn't experience high costs.

Figure 2 provides an example four different tariffs, two conventional and two dynamic, to illustrate how a dispatchable rate component can impact potential customer costs.

## Energy Cost \$/kWh

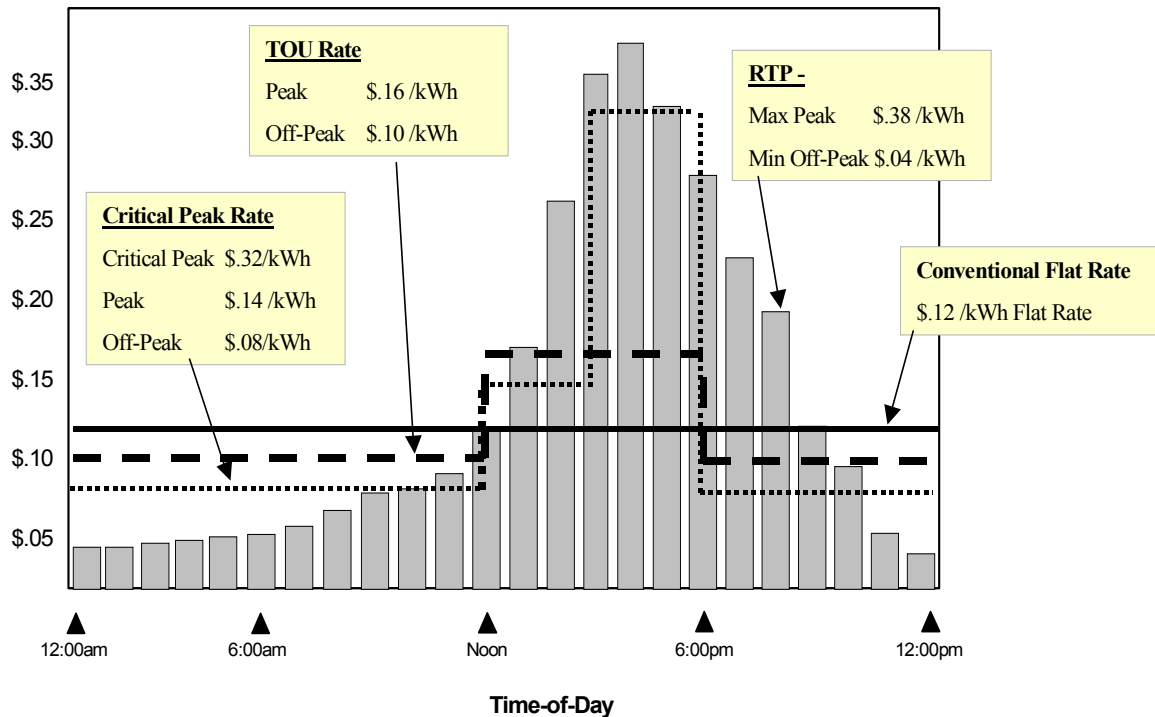


Figure 2. Contrasting Rate Impacts - Conventional vs. Dynamic Tariffs

In Figure 2, the shaded bars represent either a forecast or actual hourly price that might be seen by a customer under a real-time pricing (RTP) tariff. Under an RTP tariff, the customer sees and pays the actual hourly cost reflected in the price duration curve. In this example, the straight flat line labeled Conventional Flat Rate reflects the average of the hourly real-time prices. For this particular day, while the customer on the flat rate and RTP tariff pay the same total cost, the flat rate customer is being overcharged or undercharged in most hours. The customer on the RTP tariff has a financial incentive to control their bill by shifting energy usage into low-priced periods or by reducing usage during high cost periods. The flat rate customer has no such incentive.

The Critical Peak and TOU tariffs provide a more subtle contrast between dynamic tariffs. Both rates provide a peak and off-peak charge, however, the Critical Peak Rate also includes a dispatchable critical peak price. The critical peak price is only dispatched to capture the highest cost hours. Because of the dispatchable critical peak price, peak and off-peak prices for the Critical Peak tariff are lower than for the same time period covered by the conventional TOU tariff. For customers who normally use less power on-peak than the average, a Critical Peak Tariff will result in a lower bill. Customers who use more power on-peak than average will pay more if they do nothing to reduce their usage during critical peak periods. Again, customers on the Critical Peak tariff now have a choice to reduce their power bill by either shifting usage to lower priced hours or by avoiding or reducing usage during critical price hours.

## B. Dynamic Tariff Objectives

What is clear is that dynamic tariffs can simultaneously achieve several complementary policy goals:

- (1) Dynamic tariffs better reflect the actual cost; consequently these tariffs also assure that customers and classes of customers are treated more equitably. Customers under dynamic tariffs are much more likely to pay a fair share of costs based on when they use energy than they would under flat, non dynamic tariffs.
- (2) Dynamic tariffs provide financial incentives for customers to shift energy into low priced period and/or out of high-priced periods. Unlike conventional load control or curtailable/interruptible incentives, dynamic tariffs can be made available to all customers, regardless of overall usage level or appliance ownership. The demand response that results from customer decisions to better manage their energy costs facilitates an overall reduction in system costs and improvements in system reliability that benefit all customers.
- (3) Dynamic tariffs resolve potential conflicts between conventional tiered rates that are designed to encourage conservation and load management rates that are designed to encourage load reduction or shifting. The integration of TOU and a dispatchable critical peak price under a Critical Peak tariff provides consistent and complimentary incentives to encourage and balance the customer response.

## C. Technical Feasibility - Dynamic Tariffs Require an Advanced Metering Infrastructure

Dynamic tariffs require advance metering, communication, and enhanced billing capability. Advanced metering is necessary to capture hourly customer usage that can be matched with either critical peak or real-time hourly prices. Communication capability is necessary to support the dispatch of pricing information and for retrieval of hourly meter data. Finally, utilities will require enhanced billing and other information systems to support the more robust critical peak and real-time tariff structures.

There are significant economies of scale that favor the mandated mass implementation of advanced metering and communications, even though dynamic tariffs may not be preferred, offered or even appropriate for all customers. Mass implementation not only reduces unit incremental costs, it provides an infrastructure that enables a range of beneficial utility and customer choice options that cannot be accomplished or provided in any other way. Utility experience elsewhere indicates that many of the applications can reduce costs and produce improvements in internal operating efficiencies sufficient to fully recover or substantially offset infrastructure implementation costs.

Table 1 illustrates that the advanced metering and communication infrastructure necessary to support dynamic tariffs can also support all other conventional tariff

structures. The reverse is not true. Mass implementation would create customer choice opportunities. Retaining the current systems actually acts as a barrier to customer choice.

Table 1. Meter Compatibility with Tariff Options

Rate Options	Standard Utility kilowatt hour Meter	TOU Register	Interval Meter with
Flat Rates	●	●	●
TOU Rates		●	●
Dynamic Rates			
Critical Peak Pricing			●
Real-Time Pricing			●

Installing the infrastructure creates additional benefits beyond the ability to support dynamic pricing. Table 2 identifies some of the high-value utility and customer applications and services that can be supported with the advanced metering infrastructure, regardless of which tariff a customer might select.

Table 2. Meter Compatibility with Utility and Customer Value Added Applications

Application / Function	Standard Utility kilowatt hour Meter	TOU Register Meter	Interval Meter with Communications
<b>Utility Functions</b>			
a. Automated Meter Reading	NO	NO	YES
b. Outage Detection	NO	NO	YES
c. Theft Detection	NO	NO	YES
d. Load Survey	NO	NO	YES
<b>Customer Functions</b>			
a. Customer Rate Choice	NO	Limited	YES
b. Energy Information	NO	NO	YES
c. Enhanced Billing	NO	NO	YES

#### **D. Technical Feasibility - Dynamic Tariffs Require Customer Acceptance**

Dynamic tariffs will be appropriate for some customers and inappropriate for others, given their typical load shapes and their varying abilities to shift or reduce load. Generally, certain customer types will prefer certain tariff designs; however, individual customers may, due to their own particular circumstances, prefer a different tariff design than similar customers. Retaining a metering infrastructure incapable of supporting all dynamic tariff types will limit customer choice and increase costs.

##### **Existing Rates:**

Characteristics of customers who would benefit from current, average rates:

- Users with heavy peak demand
- Customers who don't want to be bothered and who are not budget constrained
- Customers with relatively inflexible, high-load factor load shapes (i.e. small AC-dominated commercial)

Characteristics of customers who would not benefit from current, average rates:

- Almost everyone else

Current flat rates essentially contain a “premium” for the insurance of price protection—customers pay incrementally more on every unit of energy they use to cover the cost of the few very expensive hours. While this tariff design may be the appropriate choice for some customers, other customers might prefer to have lower rates on average and specifically choose how much they want to consume during high-priced hours.

##### **Time of Use Rates.**

Time of use pricing--by definition not a dynamic price generally reflect the costs of providing power at different times. While ineffective at generating customer response to short-term system conditions or market prices, it can, depending on the prices charged and the time periods represented in the tariff, encourage customers to adopt patterns of energy use that both shift peak load to off-peak periods and reduce peak consumption absolutely. In general, the load-leveling effect of TOU rates reduces system costs.

Time of use pricing may be attractive to a large number of customers for whom short-term demand response is problematic, or for customers who have known only flat rates and are unsure of their ability to shift or reduce load. For those customers, TOU may be useful as a transition tariff as they learn about their own ability to manage their use. Some of those customers may discover down the road that they can respond with short-term notice and would be better off under a dynamic tariff design.

Characteristics of customers who would benefit from TOU rates:

- Customers whose load shape is relatively flat
- Customers for whom the cost of adapting to a variable rate is high
- Have little or no immediate control over energy consumption
- Cannot pay attention to energy consumption

Customers who would see increased costs under a TOU rate:

- Customers whose energy use is concentrated during on-peak periods but who cannot reduce or shift peak load
- Customers for whom the cost of shifting load off-peak exceeds the benefits

### **Critical Peak Pricing.**

Characteristics of customers who would benefit from CPP rates:

- Customers who have relatively flat load shapes over peak/non-peak periods.
- Customers who have load that is easily dropped for short periods.
- Customers for whom reducing the total bill is more important than maintaining their entire load during peak periods (e.g. budget constrained residential customers).

Customers who would see increased costs under a CPP rate:

- Customers whose load is concentrated on-peak and for whom maintaining that level of consumption through the peak is essential.
- Customers for whom the cost of maintaining load is less important than the increased cost. (non-budget constrained residential AC customers)

### **Real Time Pricing.**

Characteristics of customers who would benefit from RTP rates:

- Customers who have relatively the ability to shift load toward off-peak periods.
- Customers who have load that is easily dropped for short periods.
- Customers for whom the transaction costs of following rates are low compared to the potential savings
- Customers who have the ability to manage their load on an hourly basis
- High volume customers for whom incremental changes in electricity commodity costs are important

Customers who would see increased costs under a RTP rate:

- Customers whose load is concentrated on-peak and for whom maintaining that level of consumption through the peak is essential.
- Customers for whom the cost of maintaining load is less important than the increased cost. (non-budget constrained residential AC customers)
- High-volume customers whose load shape is inflexible and has a high load factor

## **Demand-Bidding Programs.**

Characteristics of customers who would benefit from demand bidding programs:

- Customers whose curtailable load is an input to a production process that can be interrupted and restarted with relative ease
- Customers whose load is large enough to be significant in system terms
- Customers whose load can be dropped with relatively short notice
- Customers for whom the ability to drop load varies (e.g. a manufacturing facility in an industry where product demand varies and could be met with inventory)

Customers who would not directly benefit from a demand bidding-style program:

- Any small customer
- Customers whose processes are dependent on constant levels of power

## **VI. Qualitative Assessment of Benefits and Costs**

SB 1976 directs the Energy Commission to examine the benefits and costs of dynamic tariffs for California electric utilities and their customers.

*Legislative requirement 2(a): "...feasibility of implementing real-time pricing, critical peak pricing, and other dynamic pricing tariffs..."*

This chapter summarizes the benefits and costs of dynamic pricing using a qualitative approach. The efforts undertaken in CPUC R.02-06-001 provide a basis for a qualitative discussion, but have not yet covered all issues in a manner that supports full quantitative assessment. The Energy Commission believes that the benefits of dynamic pricing outweigh the costs, but we cannot yet at this point provide a quantitative analysis to support our conclusion. We anticipate that improved understanding of costs will result in the phase of CPUC R.02-06-001 that examines the utility business case for advanced metering, and that the energy agencies will be able to present a basis for widespread advanced metering and dynamic pricing within the next year or two.

### **A. Benefits from Implementation**

Both participating consumers and utilities receive benefits from implementation of dynamic pricing. Through the advanced metering and information systems required to implement time differentiated and dynamic pricing options, consumers gain more information about their usage patterns and have an improved ability to control their usage and their bill. Traditional principles of utility rate design, i.e. cost-of-service pricing, can be more readily implemented with dynamic pricing and the supporting infrastructure of advanced metering systems. Correspondingly, improved information about individual

and aggregate usage helps the utility make operating efficiency improvements that save money over time. Finally regulatory processes can be simplified, and regulatory overhead costs reduced, since a number of customized tariffs and programs to ameliorate socially disadvantageous energy bills for particular customer groups can be reduced.

### 1. Support to Consumer Choice

Consumers deserve the right to know the basis for their bills. Conventional totalizing meters that simply accumulate energy use, inhibit the utility and its supervising regulatory agency from fully implementing cost-of-service rate design because the necessary information about customer usage patterns is not gathered. Rate design then is forced to treat large groups of customers in aggregate ways, even though huge differences exist in the usage patterns within these groups. The diversity that exists within these groups creates cross-subsidies, which consumer advocacy groups attempt to eliminate through creation of special programs, special usage allowances, etc. All of this creates additional overhead costs that can be eliminated by improved information about usage patterns which result from advanced metering systems.

Once the information about one's own usage is available, the customer can take actions and immediately see the results. In engineering terms, the "feedback loop" has been improved. The Puget Sound Energy advanced metering program implemented for virtually all urbanized residential and small commercial customers during 2000-2001 involved installation of an advanced metering and information system that gathered hourly usage data, uploaded it to the utility once daily, and was posted to an internet website the next day. Analysis of customer usage data and customer service records reveals improved satisfaction, reduced bill complaints, and 3-4% usage reduction with no change in pricing at all.

### 2. More Effective Implementation of Traditional Rate Design Principles

Regulatory commissions have traditionally endorsed cost-of-service as a fundamental principle to guide rate design. Unfortunately, the absence of hourly usage data for each customer and the clear variation in hourly cost of service resulting from different generators being brought on- and off-line results in cumulative usage data being used to allocate costs even though there is great variation among customers.

As an example, discounting for a moment baseline allowance differences, a small apartment occupant in a mild coastal climate zone with no air conditioner with a monthly cumulative usage of 250 kWh is charged the same \$/kWh as a large single family house with central air conditioning customer in the Central Valley regularly exposed to 100 °F temperatures. It is common sense that the central air conditioner customer with its much greater peak usage costs more to serve than the off-peak apartment customer with no air conditioning. To achieve greater equity, the Legislature has mandated the creation and use of baseline allowances that are geographic zones. These serve to reduce the bill substantially for the

small apartment dweller in the coastal zone, thus reducing somewhat the inherent problems of monthly cumulative metering.

If both customers were charged a dynamic rate per kWh based on the costs of service for that hour, then the small apartment dweller's bill would naturally be dominated by off-peak, lower cost hours while the Central Valley central air conditioner customer would have a much larger proportion of usage being charged in the more expensive on-peak hours.

The need for divisive regulatory debates about cost allocation, advocacy for legislative intervention to achieve some interest groups' idea of fair and equitable cost allocation, and utility customer service representatives fielding bill complaints would be reduced if greater information about individual customer usage were built into the rates in the first place.

### 3. Reduction in Numbers of Tariffs and Special Programs

While seemingly trivial, the number of special tariffs and programs currently in place to adjust for the perceived inequities of cumulative metering and flat pricing is staggering. There are literally hundreds of special tariffs that have been implemented over time to appease the perceived problems of various consumer groups organized around their particular usage pattern.

For example, PG&E has more than 60 agricultural rate classes that exist simply to provide bill reductions compared to the original agricultural class tariff based on different season of usage, different daily patterns of usage for on-farm irrigation patterns, ability to shift load in response to localized emergencies, etc. There are two different, full time ratepayer advocacy organizations whose costs are partially subsidized by all ratepayers through intervener compensation programs to fight to preserve "fair and equitable" cost allocation and rate design.

While dynamic pricing supported by advanced metering and information systems cannot eliminate all of this activity, it can be reduced and channeled into more technically factual debates with the assistance of improved information about customer usage patterns.

### 4. Improvements in Utility Operating Efficiencies

There are numerous implications for utility operations that result from dynamic pricing and its supporting advanced metering and information infrastructure. These include:

- Reduction in meter reading costs
- Reduction in estimated bills and resulting customer complaints
- Reduction in theft detection and prosecution costs, and the need to allocate these costs to ratepayers at large

- Reduction in customer billing complaints and more satisfied customers recognizing a fair basis for bills who do lodge complaints
- Improved information to use in rate design to allocate generation, transmission and distribution costs more accurately according to cost-of-serve
- Improved information in local distribution planning
- Improved information for use in trouble shooting power quality problems in local distribution feeders.

These changes lead to cost reductions, efficiency improvements, and more equitable allocation of costs.

## B. Costs of Implementation

There are three main sources of utility costs to implement dynamic pricing tariffs and programs. First, the investment in advanced metering and information system is somewhat larger than that required by traditional cumulative meters and “shoe leather” networks to collect this data. Second, only time-only and ongoing costs of the mechanisms that must be developed and maintained to communicate prices to customers are new. Third, the greater volume of data resulting from hourly or 15-minute interval measurements does impose larger data processing and storage costs on the utility.

### 1. Advanced Metering and Information Systems

Advanced metering and information systems consist of three basic components. Each has parallels in the traditional utility metering system, but obvious differences. First, an interval meter measures usage in 15-minute or hourly increments and records this “interval” in a way that preserves the chronological time for later use. Second, some form of telecommunication system uploads the interval usage data from the customer facility to a central data processing site. Third, the usage data in its interval, time-stamped form is posted to a website that the customer can access through the Internet using a customer-unique password to protect confidentiality.

Costs of advanced interval meters have dropped significantly, and the cost increment of such meters over traditional meters is now not very large in comparison to the installation cost of a meter. Telecommunication costs of meter reading can be highly variable, and are dependent upon: (1) the technology used (cell phone, pager, radio, telephone land line, dedicated vs. shared, etc.), (2) the density of utility customers in a given geographic area, and (3) regulatory decisions about pricing and conditions of service for regulated telecommunication services. Website posting of usage data is vastly cheaper in recent years and is the wave of the future for all kinds of consumer billing and transactions data.

## 2. Communication of Prices to Customers

Utilities will have to incur some costs to develop systems that communicate dynamic prices to customers. These costs may be negligible, such as if the dynamic price is simply the CAISO Day Ahead hourly price, which is available from the CAISO's website, or they could be considerable if the price signal was communicated electronically through a dedicated network to reach individual meters and the facilities whose loads they measure.

## 3. Bill Processing

The greater volume of data resulting from a shift from one usage value per month to 744 hours per month or 2880 15-minute intervals per month does mean that utility data processing costs will increase. Archiving usage data for use in billing disputes will increase. The software that billing systems use to process billing determinants and render a bill each month for each customer must be upgraded, and these one-time costs must be acknowledged.

## 4. Consumer Costs

To operate in an environment of dynamic pricing, consumers will likely incur some hardware and ongoing costs. Controls that respond automatically as prices change using pre-programmed decision rules can allow the customer to reduce their bills compared to continuing traditional usage patterns. These controls have costs. Customers must develop some time and energy to making choices about different pricing options, investigating the hardware systems available to respond to market prices, and to select and have installed the appropriate hardware. Some periodic attention to pricing patterns and adjustment of control systems may be appropriate. While for some consumers these "overhead" costs are not actual cash out the door expenses, they will divert the consumer from other activities. For commercial customers, these activities are real costs.

### C. The Net Benefits of Dynamic Pricing

The energy agencies believe that the balance between the costs and benefits described above is likely to be in favor of net benefits. The evidence and opinion revealed in Phase 1 of R.02-06-001 during 2002 – 2003 leads us to conclude that widespread advanced metering and dynamic pricing is desirable.

## **VII. Expected Levels of Demand Response (Peak Savings) by 2007 under Different Tariff and/or Program Options**

*Legislative requirement 2(b)(5): “Provide estimates of potential peak load reductions resulting from the tariffs, including the shifting of peak load demand to off peak periods.”*

- A. Impacts of providing time of use rates to all customers.
- B. Impacts of providing critical peak pricing option.
- C. Impacts of providing real time prices.
- D. Impacts of bidding on demand response.

<THIS CHAPTER UNDER PREPARATION >

### **VIII. Strategies or Options to Provide “Vulnerable” Customers with Effective Safeguards from Volatile Prices**

Some customer sectors will not fully realize the benefits of dynamic tariffs. The Legislature is sensitive to their needs and has directed that the Energy Commission evaluate options to protect these customers from undue billing increases.

*Legislative requirement 2(b)(7): “Options for ensuring customer protection under a real time, critical peak or other dynamic pricing scenarios, including potentially disadvantaged groups. “*

One fundamental purpose of adopting dynamic rate designs is to attenuate price volatility by giving electricity consumers the choice of not purchasing power that is priced higher than they are willing to pay. The effect of even a small percentage of customers reducing a portion of their demand in response to rising prices will be to reign in market prices, to the benefit of all customers. If, during the extraordinary market of 2001, LSE’s could have refused to buy power being offered at inflated prices because their retail customers were collectively dropping load, those high prices might never have been reached.

One element of current average price per kWh rate designs is that customers with relatively flat load profiles—the 65%-70% of residential consumers who do not have central air conditioning—are subsidizing air conditioning users because the high price of peak power is being averaged with low-cost off-peak power. Currently, the customers most “vulnerable” to paying higher bills due to dynamic pricing strategies are those customers who have high peak demand and high overall consumption. On average, customer groups typically considered “disadvantaged” or “hard to reach,” including those with low and fixed incomes, low English proficiency, low education levels, and special needs—those customers currently targeted by C.A.R.E. programs and medical baseline rates—generally have consumption levels and load profiles that would result in lower bills under TOU and most dynamic rate designs. This is largely due to the relationship of dwelling size, air conditioning ownership, and income on energy consumption.

Two general factors would lead to risk of higher bills, given no change in consumption behavior, under a dynamic tariff. The first is having a high level of energy consumption. The second is having high levels of consumption during peak hours. In general, energy consumption is positively associated with income level. People with lower levels of income are more likely to live in smaller homes and less likely to have central air conditioning.

Dynamic rate designs will shift the burden of paying for peak power onto those that consume it heavily; the higher cost of peak power for the rest of the customers will be more than offset by the lower cost of off-peak power.

To the extent some disadvantaged customers do not automatically benefit from dynamic rate designs, they should be provided explicit subsidies to support their fundamental needs for electric power. This can be accomplished through enhancement of existing identification mechanisms such as C.A.R.E. and medical baseline programs.

Explicit subsidies or rebates are to be preferred to rate discounts. It is in the interests of all customers for everyone to face the same types of price signals. Unnecessary peak usage should be discouraged among all customers by having them all see the same per kWh prices.

## **IX. Barriers and Challenges Slowing Development of Dynamic Pricing/ Demand Response Capability**

### **A. Real Barriers:**

1. Legislated
2. Customer perceptions of harm
  - a. Cost: economic impacts vs. comfort/convenience
  - b. Information burden
  - c. External Impacts: environmental pollution, etc.

### **B. Implementation Challenges:**

1. Technology markets
2. Electricity markets
3. Utility systems
4. Customer education

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## **X. Recommendations**

### **A. Background for Key Statutory and Regulatory Constraints**

1. State Laws

## 2. WECC, CAISO and FERC Standards and Regulations

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<sup>1</sup> Wolak, Frank, CAISO Market Surveillance Committee Report, September 1999, p. XX.

<sup>2</sup> CPUC, R.02-06-001, Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing.

<sup>3</sup> The New York Independent System Operator has funded studies of demand response programs impacting prices in 2002 and 2003, which find beneficial impacts by reducing market prices.

<sup>4</sup> Borenstein, Severin, Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets, The Energy Foundation, October 2002, pp. 10-11.

<sup>5</sup> The \$35 million authorized by AB29x for meters, plus additional expenditures by utilities, has resulted in 25,000 customers having an RTP metering system. It consists of an interval recording meter, an electronic communication channel to read the meter, and an internet-based website where each customer can obtain their own usage data from the day before. Further, by D.01-09-XXX, all >200 kW not then on time-of-use (TOU) tariffs were shifted to a TOU tariff once their metering system was installed.

<sup>6</sup> About 10% of the electric utility customers in the nation now have advanced metering systems, and the regulatory commissions in several western states are in various stages of deciding whether or not to make this investment.

<sup>7</sup> Draft Vision (Item 3), California Demand Response: A Vision for the Future (2002-2007) October 29, 2002.

<sup>8</sup> Report of Working Group 3 to Working Group 1, R.02-06-001, Final Version 5, December 10, 2002, page 18.

<sup>9</sup> *Ibid*

<sup>10</sup> Literature Survey of Electricity Residential End-User Demand-Response to Price Changes, Chris S. King and Sanjoy Chatterjee, May 2003.

<sup>11</sup> Own price elasticity estimates are summarized here only.

<sup>12</sup> Canada, the U.K., France, Switzerland, and Denmark.

<sup>13</sup> *ibid* footnote 4

<sup>14</sup> *ibid* footnote 4

<sup>15</sup> *ibid* footnote No. 2, page 6.